Updating the Regulatory Settings for Distribution Networks

Submission on the Electricity Authority's Discussion Paper

28 September 2021

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1. Introduction

1.1. Preliminary

1. We welcome the opportunity to submit our views in response to the Electricity Authority's (the Authority's) consultation – "Updating the Regulatory Settings for Distribution Networks" (Discussion Paper).

2. No part of our submission is confidential.

1.2. Context

3. New Zealand's electricity sector is facing a period of significant and relatively abrupt change, driven by the Climate Change Response (Zero Carbon) Amendment Act 2019 which, *inter alia*, seeks to reduce net emissions of all greenhouse gases (except biogenic methane) to zero by 2050. Further fuelling this change, at a sector level, is the Government's aspirational goal of reaching 100 percent renewable electricity generation by 2030.

4. It is widely recognised that transitioning to a low emissions economy will involve electrification of transport and of process heat. Large industrials are now actively investigating electrification of boiler systems and the Clean Car Discount (feebate) scheme saw electric and hybrid light vehicle registrations set a new monthly peak of 1,944 in July 2021, up 236% on the prior 12-month average of 578[1].

5. Electrification and retirement of thermal generation plant can be expected to increase both base and peak demand, resulting in necessary investment in new generation, connection assets, and enhanced transmission and distribution capacity.

6. Effective use of distributed energy resources (DER) can assist distributors to manage peak demand and defer investments in network capacity. For consumers, not only does this mean that line charges can be minimised in the short-to-medium term, but DER owners can receive a financial benefit while contributing to that deferral, alongside other benefits of DER ownership, including energy arbitrage and energy export payments.

1.3. General

7. We commend the Authority for initiating this important discussion. Given the rapid sectoral change that is expected, and the significant time that it takes to draft, model, test, consult on, and implement regulatory setting changes, it is important that this discussion takes place now.

8. We have some general concerns about the approach to this discussion, however:

[1] Ministry of Transport. 2021. Monthly EV statistics. Available from https://www.transport.govt.nz/statistics-and-insights/fleet-statistics/sheet/monthly-ev-statistics

8.1. The inclusion of potential interventions in the Discussion Paper is an unhelpful distraction, as it inevitably draws attention toward defending positions rather than considering the wider issues. As a consequence, we expect that a number of submissions will be defensive in nature, protecting individual interests rather than considering the issues from a wider 'New Zealand Inc.' and consumer-centric perspective.

8.2. In our view, the Discussion Paper does not adequately recognise that DER and flexibility services are not a panacea for the demand challenges presented by electrification. There will be a real and unavoidable need for significant investment in network capacity as base demand from electrification grows; however, where and when those investments will be needed will likely be influenced by:

- the existing headroom capacity of network segments;
- the rate of base demand growth;
- Consumers' uptake of appropriate DER; and
- the timing and efficacy of flexibility services market development.

8.3. The Discussion Paper is short on evidence and long on speculation that distributor's regulatory settings are impeding the uptake of DER and development of flexibility services. Submissions on the Discussion Paper may indicate areas for further consideration, but are unlikely to be definitive at this stage.

9. As such, it's difficult to see how the Authority expects it can swiftly move to a preferred option on which it will consult[2] without additional steps to collect objective evidence. For example, in relation to the Discussion Paper's analysis of distributors' capability and capacity, it's a giant leap to (1) establish that a significant problem exists purely on the basis of submissions and then (2) decide that a single distribution system operator (DSO) model is the likely solution, especially when many in the industry are still contemplating what is, and is not, a DSO function relative to a distribution network owner. Has the Authority considered whether a single DSO model is appropriate in a two-island system (albeit connected at the transmission level)?

10. Aurora recommends that the Authority focusses on an approach that is evidence-based, incremental, proportionate, and founded on a principle of 'least regrets'. Potential issues surrounding DER ownership and provision of flexibility services are at best nascent, and now is not the time for radical reform.

2. Specific Focus Areas

2.1. Information on power flows and hosting capacity

11. Aurora acknowledges that flexibility traders will need information on congestion and hosting capacity so that they can develop and offer appropriate flexibility services. Some information of this

[2] Discussion Paper, paragraph 1.20, p12.

nature is already available through information disclosures made under Part 4 of the Commerce Act 1986 - asset management plans typically identify the development needs of the network, including alleviation of capacity and demand constraints. Additionally, distributors are required to provide maps of anticipated expenditure and network constraints as part of their annual performance disclosures. However, we expect that in the short- to medium-term, opportunities will be signalled by distributors through requests for proposals, similar to our approach to procuring flexibility services in the upper Clutha (Wānaka and environs) region.

12. Before output information can be provided to DER investors and flexibility traders, distributors require deeper and more granular visibility of their low voltage networks (input information).

2.1.1. Direct Access to Metering Data is Key

13. Access to metering data is key to efficiently achieving low voltage network visibility, and is a significant barrier at present. Network access to appropriate advanced metering data obviates the need for alternative investments in network instrumentation, sensors and associated communications platforms, keeping costs down for all consumers.

14. Advanced metering data can assist distributors in two respects – network planning and real-time operations:

14.1. Data for network planning is not overly time sensitive, and generally involves looking at historic data and inferring trends. The current, regulated 'Default Data Template' approach (including unregulated developments and improvements to the template agreed between ERANZ and the ENA) does not, in our view, prevent access to advanced metering data for planning purposes. We do share the concerns of many distributors, however, that the process of acquiring the data is slow, bureaucratic and inefficient.

14.2. Data for real-time operations would involve timely data feeds for instantaneous demand, voltage, power factor, and last gasp. The data generally does not require the cleansing and validation activities that are associated with billing and reconciliation. For very obvious reasons, advanced metering data supporting real-time operations cannot be sourced via the regulated 'Default Data Template' approach.

15. Aurora envisages a future where advanced metering infrastructure is seamlessly integrated into the distribution power system, and not just a last-step, billing appurtenance. To achieve this vision, however, it is likely that greater hardware standardisation will be required – not picking winners and losers, but specifying minimum standard functionality that must be met by all advanced meters. Depending on how standardisation is specified, incentives may be required for metering equipment providers to replace early generation advanced meters that do not meet the minimum specification.

16. We note that the Authority has published advanced metering guidelines[3] and an advanced metering policy[4]; however, we have the following concerns with those documents:

- they are advisory in nature, and are not binding;
- they continue to focus heavily on billing, reconciliation and remote field services activities (disconnections / reconnection). While network management and demand-side management benefits are mentioned within these documents, any discussion is adjunctive to traditional metering use; and
- The documents are very dated, being now over a decade old.

17. We consider that the minimum technical standards for advanced meter functionality should include:

- instantaneous kW;
- voltage;
- power factor;
- harmonics; and
- 'last gasp'[5].

18. Seamless integration of advanced meters into the power system is likely to require a centralised information exchange from which distributors' distribution management systems and outage management systems can receive real-time data. For planning data, we consider that a centralised repository of reconciled data would be appropriate.

19. In addition to demand and flexibility management, enhanced visibility of distributors' LV networks will lead to a proactive approach to power quality management, safety management, capacity management and power flows, thus resulting in better customer service and customer experience outcomes.

2.1.2. Competition

20. Aurora is concerned that the market for metering services exhibits little or no competition, and that there is little or no likelihood of a substantial increase in competition. Figure 1, below, shows that an effective oligopoly exists in the advanced meter space, being dominated by Vector Metering and IntelliHub with a collective 88 percent of the market. If all types of meter are considered, that market share falls only marginally to 84 percent.

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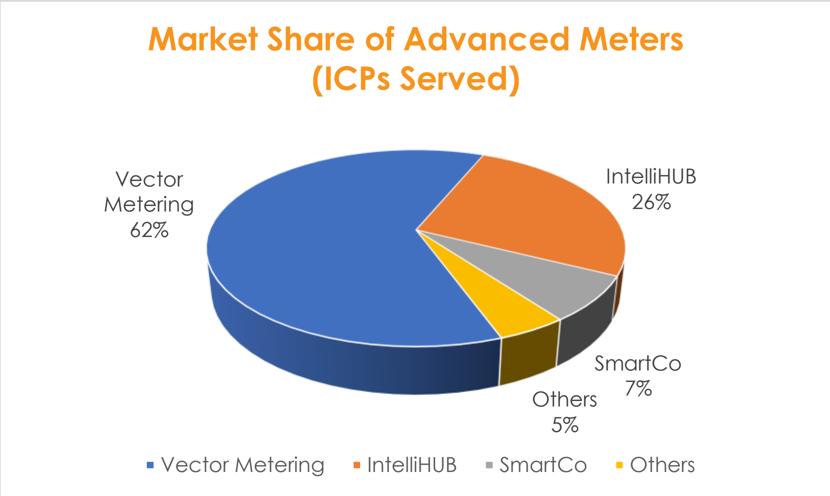
3 Electricity Authority. (2010). Guidelines on Advanced Metering Infrastructure. Version 3.1: Retrieved 17 September 2021 from Electricity Authority website: https://www.ea.govt.nz/assets/dms-assets/8/8573Guidelines-on-Advanced-Metering-Infrastructure.pdf

4 Electricity Authority. (2010). Advanced Metering Policy. Version 1.1: Retrieved 17 September 2021 from Electricity Authority website: https://www.ea.govt.nz/assets/dms-assets/8/8596Policy-on-Advanced-Metering.pdf

5 Last gasp messages are transmitted by advanced meters when a loss of power is detected.

Figure 1: Market Share of Advanced Meter Deployments (ICPs Served)[6]



21. Our concern is that the market for metering services may not be structured to efficiently support the sectoral change needed to integrate DER and provide future system flexibility. Metering equipment providers and meter data managers will undoubtably face additional costs if metering is to be seamlessly integrated into the power system, and those costs will need to be recovered. Metering services providers are entitled to a fair return on their metering infrastructure, and recovery of their operating costs; however, as it stands, the metering services market seems to be geared to toward value compensation – charging on the basis of the value of the services, and disconnected to the cost of service.

22. We do not argue that distributors and others should access metering data services for free, but note that, at present, metering costs are largely recovered from retailers for access to billing consumption data. It is only reasonable that distributors and others that require data access for network management / flexibility management purposes should fund the incremental cost of providing that data. In our view, though, this should not result in metering service providers earning abnormal returns, and must be supported by transparent information disclosure.

2.2. Electricity Supply Standards

23. We consider that there are a couple of areas where review of standards and existing regulatory settings would be beneficial:

23.1. The Electricity (Safety) Regulations 2010 should be reviewed to ensure that a comprehensive range of DER is considered and appropriate regulations developed to ensure that safety is specified and assured. We understand that the Ministry of Business, Innovation and Employment (MBIE) has a review in progress, and we would expect standards for DER safety to be addressed. We specifically recommend the MBIE amends regulation 28(1) to permit a wider operating voltage range, similar to that mandated in Australia. A voltage range of -6% to +10% from standard low voltage is likely to help

6 Source: Electricity Authority - Electricity Market Information website www.emi.ea.govt.nz

manage voltage issues associated with solar PV clustering, without adversely impacting consumers.

23.2. Part 6 of the Electricity Industry Participation Code 2010 (the Code) requires an extensive review, including:

- developing more realistic timeframes for assessing larger distributed generation (DG) applications (>10kW). This is especially important in a future where DG applications are expected to accelerate, and current assessment timeframes are insufficient;
- reviewing the prescribed maximum fees for recovering costs incurred by EDBs in assessing DG applications. With the exception of fees associated with Part 1A applications, and for correction of GST treatment, the fees have remained unchanged since 2007 and have declined significantly in real terms. The cost of assessing applications can be significant, and the prescribed maximum fees are generally insufficient for assessing larger DG applications. Given the complexity of very large DG connections (>1MW), we consider that the cap should be removed and 'actual and reasonable' cost recovery permitted;
- consideration of DER assets more broadly, including requirements for EV charging facilities and similar technology to be notified to distributors;
- reviewing the pricing principles to remove the incremental cost cap and permit fair allocation costing to be applied. It is unsustainable for distributed generators' charges to be effectively limited to recovery of connection costs, thereby 'free-riding' the core network. The consequence for consumers is that, while they benefit from the scale effect of more consumers connecting to and using the network, the same cannot be said when new stand-alone generators connect;
- reviewing of the regulated terms of connection to incorporate standard commercial terms that are currently missing (e.g., charges, billing & payment, liability, information exchange, service standards, etc.).

24. In Aurora's view, regulatory processes need to be modernised so that they are adaptive and keep pace with 'real world' change. As an example, technical standards frequently evolve faster than the regulations in which they are specified, rendering reliance on revised technical standards moot, since earlier versions remain 'locked in'.

2.3. Market Settings for Equal Access

2.3.1. Preferred Settings

25. Aurora prefers a competitive market setting for flexibility services, and generally agrees that in-house solutions can be problematic, as they become locked in as a distribution alternative, and are unlikely to be allocated to their highest value use (i.e., value stacking is precluded). However, distributors should not be constrained from investing in flexibility solutions provided that they have

(1) run a contestable procurement process and (2) failed to elicit a reasonable commercial response (or any response at all). Effectively, distributors must have the capability to become the provider of last resort. Further, it will also need to be recognised that there will be residual distributor-owned flexibility solutions that will be in play for some time (e.g., traditional demand management through ripple control).

26. In assessing the potential for market development, we expect to see an evolution of flexibility services over time, from distributor-led to price-led:

- Distributor-led - largely an extension of hot water management via ripple control, which may be extended to control of EV charging and battery storage;
- Market-led – distributors typically have standing offers for flexibility services and call on them as required (e.g., SolarZero's upper Clutha offering); and
- Price-led - dynamic pricing is driving the market – not sending a control signal, instead just a price-signal to elicit a consumer response (potentially through a flexibility trader or other form of market intermediary). Effectively, this involves location specific and variable distribution nodal pricing, which will rely on real-time data and significant automation.

2.3.2. Free DER Services

27. We have considered the Authority's comments on the provision of free DER services[7]. Our view is that provision of free DER services by distributors, like EV charging, may have been useful to stimulate markets, but can only sustained for a limited period and ultimately, when use is excessive or prolonged, may hinder the development of competitive market services. We expect that organisations like ChargeNet can speak more authoritatively on the chilling effect on market development that free DER services pose.

2.3.3. Pace of Adoption

28. The Authority characterises distributors' progress toward the use of flexibility services as slow[8] and surmises that distributors that aren't actively exploring the use of flexibility services or may prefer to invest in networks instead. We consider that there may be a number of valid reasons why progress toward the use of flexibility services appears slow, especially recognising that the market for flexibility services is immature, and not all distributors' circumstances will be the same:

- some distributors, especially those with limited growth, may be unconstrained;
- some distributors may be able to manage demand growth adequately, for the foreseeable future, with legacy ripple control plant;
- some distributors are actively pursuing flexibility services as a long-term alternative or supplement to traditional ripple control; and

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7 Discussion Paper, paragraph 6.13.

8 Discussion Paper, paragraph 6.10

– some distributors may be facing demand challenges that are too significant to be mitigated by procurement of flexibility services, and need to make immediate network investments (after which, they become unconstrained for a period).

2.3.4. Economic Regulation

29. In assessing distributors' apparent preference for implementing capital solutions over procuring flexibility services, the Discussion Paper refers to submissions to, and findings of, the joint Authority / Commerce Commission (the Commission) project – "Spotlight on emerging contestable services"[9].

30. The Discussion Paper contends that the two predominant factors that influence distributors' apparent decision to favour capital investment rests with the determination of the regulated weighted average cost of capital (WACC) and expenditure efficiency incentives provided by the incremental rolling incentive scheme (IRIS), both of which apply to fully regulated distributors.

30.1. WACC. The argument that distributors are over-compensated by a WACC estimate set at the 67th percentile, rather than the 50th, is longstanding and repeated by some stakeholders at every opportunity. The argument was successful in bringing the estimate down from the 75th percentile to the 67th during the last input methodologies (IM) review in 2014. We expect further attacks at the next IM review, scheduled for completion in 2023. In our view, while the margin above the mid-point estimate of WACC properly provides an incentive for timely investment over risky under-investment, 17 percentage points is not sufficient in and of itself to sustain a preference for capital investment over procuring network alternatives. This, to us, is especially true given that the WACC is an estimate, and that in some cases the margin serves to accommodate variance caused by the difference between reality and economic theory (including the WACC methodology itself).

30.2. IRIS. We consider that the IRIS structure may provide a reasonably weak incentive to favour in-house solutions because, while the retention factors are equal for capex and opex, distribution assets typically have very long lives and the capex IRIS acts on amortised values. Therefore, the capex incentive has a lower impact on revenue compared to an equivalent value of opex. The IRIS mechanism acts on overspent amounts above the expenditure allowances set by the Commission in default and customised price-quality paths, and therefore has two implications:

– it will become increasingly important for the Commission to adopt a mechanism that can compensate for demonstrably incorrect expenditure setting, especially in the face of the significant planning uncertainty expected with electrification; and

– assuming that expenditure allowances are set correctly, without changes to the IRIS mechanism, it will remain difficult for distributors to forego a capex solution for network alternatives (opex), as this will result in real losses being incurred.

9 Discussion paper, paragraph 6.11

Demonstrably prudent and efficient flexibility services could be categorised as a recoverable cost under price-quality regulation, which would avoid those disincentives. To be clear, however, this does not point to a reasonable argument for higher capex retention factors in the IRIS mechanism, nor are we advocating such a position.

31. While the above factors could go some way to explaining a proclivity toward network investment it cannot, in our view, be a complete explanation when it is considered that 40 percent of distributors escape price-quality regulation and the associated WACC and IRIS effects.

2.3.5. CBA

32. We acknowledge the comprehensive cost-benefit analysis undertake by Sapere; however, we choose not to provide technical comment on the analysis, as we have simply not been able to do that work. While analysis of this type provides useful guidance, it is typically characterised by assumptions that are broad and many. However, in our view, the analysis does point to the broad economic utility of flexibility services.

2.4. Operating Agreements

33. We acknowledge that standardisation of operating agreements has the potential to lower costs in the long run; however, we have concerns that the materiality of those costs have historically been exaggerated, especially when set against the value of related network investments.

34. We recommend that extreme caution should be exercised if the Authority considers, at this early stage, that it should develop regulated terms. In part, this recommendation is driven by the infancy of flexibility services, and also by the Authority's track record in developing regulated terms, which has not always been effective:

- The regulated terms of connection of distributed generation (schedule 6.2 of the Code) omit many common commercial terms for an agreement of this type, and are generally unsuitable for all but the smallest generation connections; and
- The default distributor agreement (DDA), while mostly workable, fails in its allocation of risk. Distributors are allocated liabilities when, in fact, the counter-party is best placed to manage the associated risk.

35. Aurora would support development of guidance for operating agreements, incorporating best practice terms that may be voluntarily adopted, provided that the guidance is first genuinely consulted on. Such consultation must clearly explain the approach for each clause, or relevant grouping of clauses, especially where risk allocation is concerned. Further, guidance should specifically consider the different Part 4 regulatory settings for fully and partially regulated distributors, especially in terms of quality standards. Distributors face significant penalties for contravening quality standards, and the risk is elevated when distributors have to rely on third parties to achieve regulated reliability outcomes.

36. As the Authority has noted, Aurora has contracted for flexibility services in the upper Clutha region of its network. In doing so, we have had to develop contract documents to govern arrangements.

Aurora has been sharing its flexibility services contract documents with another distributor and, as successive changes occur, the core document is moving, in our view, toward a best practice example. We remain open to sharing that agreement, on a similar basis, with other distributors that are contemplating procuring flexibility services.

37. In time, and in the context of a demonstrably maturing market for flexibility services removing some uncertainty, Aurora could support a well-constructed 'DDA style' default agreement. There is benefit to distributors in managing relationships with multiple parties according to common terms. Despite the failings of the DDA (above), it's our observation that most distributors have recognised this value and have adopted the DDA as their contracting terms.

38. It should be noted, however, that imposing a 'DDA style' default agreement may inflict additional costs on distributors that already have an operative 'standard' contract for engaging flexibility services, and Aurora is of the view that any future default agreement should not interfere with existing agreements.

39. Finally, in the context of our comments in section 2.1.1 regarding seamlessly integrating metering infrastructure into the distribution system, we consider that there is likely to be a need for a standardised data access agreement, with potentially differentiated terms applying to real-time data access, and access to reconciled 'planning' data (the latter potentially concerning existing electricity retailers in the context of data access by distributors that may be considering entering the retail market).

2.5. Capability and Capacity

40. Aurora expects that distributors will have, or can access, the necessary capability and capacity to integrate DER and adjust to network transformation. This does not mean that every distributor will, or can, go it alone. We see examples of emerging collaboration on this and other topics across the sector:

- the South Island DSO investigation group;
- the Electricity Networks' Association's (ENA) network transformation roadmap;
- the ENA's distribution pricing working group; and
- the Wellington Electricity / EECA / GreenSync EV thinktank.

41. While we acknowledge the Authority's concerns that having 29 distributors across the country is not necessarily efficient, we consider that the evidence is inconclusive. In 2018, TBD Advisory, on behalf of seven distributors and five generator-retailers, assessed the issue of distributor scale efficiency as part of input to the Electricity Price Review[10]. In response to the question "Does fragmentation of EDBs increase cost for some electricity consumers where those costs could be reduced by eliminating barriers", TBD's key findings were that:

[10] TBD Advisory. (2018). *Estimated Efficiency Gains from Amalgamation of Electricity Distribution Businesses*. 31 August 2021. Retrieved 3 September 2021 from TBD Advisory website: https://www.tdb.co.nz/wp-content/uploads/2018/09/Efficiency-Gains-from-EDB-Amalgamation.pdf.

– there is no robust evidence of sizeable efficiency gains from amalgamating EDBs. Apparent gains in aggregate asset operating costs from amalgamating small EDBs can be fully accounted for by differences in customer density.

– Customer density and - to a much lesser degree - size influence the more-labour-intensive component of operating costs, leading to the conclusion that there may be some small gains from amalgamating EDBs, before allowing for the costs of amalgamation.

– there are significant cost differences between EDBs which cannot be explained by size or density.

42. Despite this, we expect that there may be some effective consolidation across the sector as some distributors find it more efficient to seek management arrangements. PowerNet's management of Electricity Invercargill, The Power Company (Southland), OtagoNet (East Otago), Stewart Island Electrical Supply Authority, and Electricity Southland (Frankton suburb, Queenstown) provides an example of what is possible under such arrangements.

2.5.1. Error Correction

43. We make no specific comment on the observations in the Discussion Paper, sourced from the International Energy Association's (IEA) 2017 report on New Zealand's Energy Policy[11], that some community owned trusts and local authority-owned distributors have inappropriately or unwisely invested in non-core assets – that is a matter for those entities to address. However, we must correct the record in regard to the example of Delta Utility Services (**Delta**), which was cited by the IEA and the Authority as a business unit of Aurora Energy. The facts of the matter are that:

– Delta has never been a business unit of Aurora;

– Delta was a subsidiary company of Dunedin Electricity Limited (now Aurora) until 2003; and

– From 2003 to present, including the time during which Delta undertook commercial property development, Delta was owned by Dunedin City Holdings as part of a diversified investment portfolio and therefore has a sibling relationship to Aurora.

44. The inability of the IEA to undertake basic fact checking regarding Delta's ownership arrangements validates and reinforces the repudiation of the conclusions of its 2017 report (Chapter 7) given by Professor George Yarrow, and his criticism that the report lacked an evidential basis.[12]

2.6. Efficient Pricing

45. We note that the Authority published its consultation paper on its revised distribution pricing practice note[13] on Tuesday 21 September 2021.

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11 International Energy Agency. (2017). *Energy Policies of IEA Countries: New Zealand 2017 Review*. Retrieved 17 September 2021 from IEA website: https://www.iea.org/reports/energy-policies-of-iea-countries-new-zealand-2017-review

12 Yarrow. G. (2018). *The International Energy Authority's 2017 Review of New Zealand*. Retrieved 17 September 2021 from Energy Trusts of New Zealand (ETNZ) website: https://etnz.org.nz/submissions-presentations/

13 Electricity Authority. (2021). *Supporting reform to efficient pricing: a refreshed Distribution Pricing Practice Note*. Available from https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/consultations/#c18986

46. Aurora recognises the key role that efficient distribution pricing will need to play in transitioning to a low emissions future at least cost. We have recently put significant effort into developing our pricing strategy and roadmap that, together, signals our initial pathway[14] toward more cost-reflective distribution pricing.

47. We look forward to providing our views on the revised practice note by 3 November 2021.

14 We describe this as an initial pathway, as we expect distribution pricing to evolve significantly over time as we understand how consumers respond to the decarbonisation challenge.

Appendix A. Consultation Questions

Information on power flows and hosting capacity

Q.1 Have you experienced issues relating to a lack of information or uneven access to information?

We have generally found retailers to be accommodating with our relatively modest data requests to-date. However, we remain of the view, as outlined in section 2.1.1 above, that the Default Data Template approach will not be sufficiently agile in an environment where distributors will be looking to automate systems with real-time advanced metering data inputs.

Q.2 What information do you need to make more informed investment and operation decisions?

As noted in section 2.12, above, Aurora considers that the visibility of its low voltage would be enhanced by access to advanced metering data that includes instantaneous kW, voltage, power factor, harmonics, and 'last gasp'. Measurement capability should be enshrined in minimum technical standards for advanced meters, along with 'last gasp' capability.

Further, as discussed in section 2.2 above, distributors need to understand the DER that is installed on their networks and, as such, Part 6 should be amended to require that data to be reported to distributors, as occurs for distributed generation.

Q.3 What options do you think should be considered to help improve access to information?

In section 2.1.1, above, we outlined our vision that, in future, metering infrastructure seamlessly integrates into the distribution power system. In such a future:

- minimum standards are specified and which must be met by all advanced meters;
- a centralised information exchange is developed to support distributors' real-time operations; and
- a centralised data hub for reconciled metering data is maintained for all participants.

Electricity supply standards

Q.4 Have networks experienced issues from the connection or operation of DER?

We have not experienced any issues to-date. However, proliferation of privately owned EV chargers or other similar technology that does not currently need to be notified to EDBs could impact the low voltage network significantly in the event of rapid uptake.

For this reason, we have recommended in section 2.2, above, that a review of Part 6 of the Code is needed, and which should consider DER assets more broadly, including requirements for EV charging facilities and similar technology to be notified to distributors.

Q.5 Do the Electricity (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term and (b) in the longer term?

Yes. In section 2.2, above, we noted that the Electricity (Safety) Regulations 2010 should be reviewed to ensure that a comprehensive range of DER is considered and appropriate regulations developed to ensure that safety is specified and assured.

We specifically recommended that regulation 28(1) be amended to permit a wider operating voltage range, similar to that mandated in Australia. A voltage range of -6% to +10% from standard low voltage would likely help to manage voltage issues associated with solar PV clustering, without adversely impacting consumers.

Q.6 Does Part 6 remain fit for purpose? If not, what changes do you think are needed (a) in the near term and (b) in the longer term?

No. In section 2.2, above, we noted that Part 6 requires an extensive review to:

- develop more realistic timeframes for assessing larger DG applications;
- refresh the prescribed maximum fees for assessing DG applications so that they align more closely with distributors actual costs;
- consider DER assets more broadly, including requirements for EV charging facilities and similar technology to be notified to distributors;
- refresh the pricing principles to remove the incremental cost cap and allow fair allocation costing, especially for larger DG that is not associated with load; and
- refresh the regulated terms to incorporate many missing standard commercial terms.

Q.7 Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?

No response.

Q.8 What standards should be considered to help address reliability and connectivity issues?

No response.

Q.9 Is there a case to look at connection and operation standards under Part 6 with a view to mandating aspects of these standards?

No response.

Market settings for equal access

Q.10 What flexibility services are you pursuing?

Aurora has currently contracted for capacity support in the upper Clutha area. We are also considering areas where reactive power support might also be contracted.

Q.11 Are flexibility services being pursued through a competitive process?

Yes. We ran registration of interest and request for proposal processes.

Q.12 What options should be considered to incentivise non-network solutions?

For distributors, this normally involves a capex versus opex decision and, as noted in section 2.3.4 above, fully regulated distributors may face some disincentives to adopt an opex solution. Demonstrably prudent and efficient flexibility services could be categorised as a recoverable cost under price-quality regulation, which would avoid those disincentives.

Q.13 What options would encourage competitive procurement processes for flexibility services?

Agreements for flexibility services should be non-exclusive, allowing other flexibility traders to participate as the market grows. Additionally, if contracts are relatively short-term (1-2 years), this allows a further opportunity for greater competition.

Operating agreements

Q.14 Have you experienced difficulties with negotiating operating agreements for flexibility services?

No. While the agreement for flexibility services in the upper Clutha took some time to develop, it was not unexpected.

Q.15 Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?

We don't consider that the cost of developing agreements is a barrier, per se; however, as noted in section 2.4, above, there are likely to be benefits from, and Aurora would support, guidance for operating agreements that incorporates best practice terms that may be voluntarily adopted, provided that the guidance is first genuinely consulted on.

Q.16 Would an operating agreement help lower transaction costs and level negotiating positions?

As outlined in section 2.4, above, we have concerns that the materiality of transaction costs associated with negotiating operating agreements have historically been exaggerated, especially when set against the value of related network investments.

In time, and in the context of a demonstrably maturing market for flexibility services removing some uncertainty, Aurora could support a well-constructed 'DDA style' default agreement.

It should be noted, however, that imposing a 'DDA style' default agreement may inflict additional costs on distributors that already have an operative 'standard' contract for engaging flexibility services, and Aurora is of the view that any future default agreement should not interfere with existing agreements.

Q.17 What kind of operating agreement would address the issues described in this chapter?

No response.

Capability and capacity

Q.18 What are distributors doing to ensure their network can efficiently and effectively manage the transformation of networks?

Distributors are actively planning for the network evolution that will underpin electrification and decarbonisation. Aurora is actively contracting for flexibility services. The best source of information to understand specific network transformation initiatives is to examine individual distributors' asset management plans.

Q.19 How are distributors currently working together to achieve better outcomes for consumers?

Yes. In section 2.5, above, we gave four non-exclusive examples of where distributors have been collaborating with each other, and with others:

- the South Island DSO investigation group;
- the Electricity Networks' Association's (ENA) network transformation roadmap;
- the ENA's distribution pricing working group; and
- the Wellington Electricity / EECA / GreenSync EV thinktank.

Q.20 Could more coordination between distributors improve the efficiency of distribution?

We consider that this work is already underway, and will keep pace with the needs of DER / flexibility management. In Aurora's view, a far greater contribution toward distribution efficiency would be driven by a move to seamlessly integrate advanced metering infrastructure into the distribution power system, as outlined in section 2.1.1, above. This will require significant cross-sector collaboration, including Authority input.